Docket: : A.11-11-002
Exhibit Number : DRA-3
Commissioner : Florio
ALJ : Long
Witness : Lee

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company

Valve Enhancement Plan

San Francisco, California
June 19, 2012

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ATTACHMENTS

I. INTRODUCTION

This exhibit presents the analysis and recommendations of the Division of Ratepayer Advocates (DRA) regarding the proposals of Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) for their Valve Enhancement Plan (VEP).

SoCalGas and SDG&E (collectively referred to as Sempra or the Sempra utilities) submitted testimony and workpapers[1] in response to Commission Decision 11-06-017. Decision (D.) 11-06-017 direct California natural gas utilities to consider retrofitting pipeline, "where appropriate," to allow for improved shutoff valves.[2] In addition, the Commission has been directed by the state Legislature to consider requiring installation of automatic or remote control valves for intrastate gas transmission pipelines. The California Natural Gas Pipeline Safety Act of 2011 states,

> ...the commission shall require the installation of automatic shutoff or remote controlled sectionalized block valves on both of the following facilities, *if it determines those valves are necessary for the protection of the public: (*A) Intrastate transmission lines that are located in a high consequence area. (B) Intrastate transmission lines that traverse an active seismic earthquake fault.[3]

In this report, DRA presents its review of the SoCalGas/SDG&E proposed Valve Enhancement Plan. DRA's report considers Phase 1A of the Sempra Plan, which covers Years 2012 to 2015. DRA recommends that SoCalGas/SDG&E

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[1] Testimony of Southern California Gas Company and San Diego Gas & Electric Company in support of Proposed Natural Gas Pipeline Safety Enhancement Plan, August 26, 2011. On December 2, 2011, the utilities submitted Amended Testimony of Southern California Gas Company and San Diego Gas & Electric Company in support of Proposed Natural Gas Pipeline Safety Enhancement Plan, (Amended Testimony) and Amended Workpapers (Workpapers).

[2] *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans* (June 9, 2011), D.11-06-017, Ordering Paragraphs 4 and 8.

[3] Public Utilities Code Section 957, emphasis added.

submit for consideration any projects beyond Phase 1A in its subsequent General Rate Cases (GRCs).

In Phase 1A, SoCalGas/SDG&E propose upgrading existing manual control valves to automatic shutoff valve/remote control valve (ASV/RCV), upgrading existing ASV with RCV functionality, adding new ASVs/RCVs to the pipeline system, and installing various system enhancements. The Sempra utilities request $149 million for the Valve Enhancement Plan work that Sempra proposes to do in Phase 1A. The cost summary of Sempra's proposal is shown by year in Table 1.

Table 1. Proposed VEP Cost Summary for Phase 1A[4]

(in thousands of dollars)

SoCalGas	2012	2013	2014	2015	Total
Capital	$26,254	$28,474	$32,719	$33,321	$120,768
O&M	$ 64	$ 192	$ 730	$ 945	$ 1,931
Total	$26,318	$28,666	$33,449	$34,266	$122,699
SDG&E					
Capital	$ 5,342	$ 6,367	$ 7,120	$ 7,120	$ 25,949
O&M	$ 17	$ 102	$ 253	$ 267	$ 639
Total	$ 5,360	$ 6,469	$ 7,373	$ 7,387	$ 26,589

DRA reviewed the SoCalGas/SDG&E's testimony and workpapers, and the utilities' responses to DRA's data requests. Based on this analysis, DRA recommends adjustments to the schedules and expenditures in several areas. DRA's overall recommendations for expenditures in Phase 1A are contained in Section II of this exhibit. In Section III, DRA describes in more detail the reasons for its recommendations.

[4] Amended Testimony, p. 113, Table IX-12. Footnote 67 to that Table state: "numbers may not add up due to rounding."

II. SUMMARY OF RECOMMENDATIONS

DRA recommends that the Commission:

- consider in this proceeding only the Phase 1A proposals of the SoCalGas/SDG&E Valve Enhancement Plan;
- reduce by $88 million the combined Phase 1A capital and O&M expenditures requested by the Sempra utilities, as set forth in Table 2;
- direct SoCalGas/SDG&E to seek ratepayer funding for their Phase 1B and Phase 2 Valve Enhancement Plan proposals with supporting and detailed cost/benefit analyses in their General Rate Case filings.

Table 2. DRA Recommended VEP Cost Summary for Phase 1A
(in thousands of dollars)

SoCalGas	2012	2013	2014	2015	Total
Capital	$ 3,312	$13,378	$15,699	$15,698	$ 48,087
O&M	$ 33	$ 148	$ 654	$ 732	$ 1,567
Total	$ 3,345	$13,526	$16,353	$16,430	$ 49,654
SDG&E					
Capital	$ 3,090	$ 2,690	$ 3,083	$ 3,083	$ 11,946
O&M	$ 8	$ 29	$ 114	$ 127	$ 278
Total	$ 3,098	$ 2,719	$ 3,197	$ 3,210	$ 12,224

Table 3 shows a comparison of SoCalGas/SDG&E's total proposed expenditures and DRA's recommendations. DRA's proposes a more gradual upgrading of existing manual valves to ASVs/RCVs, ASVs to RCVs, and the installation of new valves. DRA's approach will give the utilities and the Commission time to gain more cost, operation, and installation experience to determine if the

Sempra upgrade plan is "...necessary for the protection of the public"[5] and likely to achieve these objectives. DRA recommends that some of the enhancements SoCalGas/ SDG&E propose be considered in future GRCs after the initial installations, progress, and program can be evaluated in a comprehensive manner.

Table 3. Comparison of SoCalGas/SDG&E Proposed and DRA's Recommended Phase 1A VEP Expenditures[6]
(in thousands of dollars)

	SoCalGas Capital	SoCalGas O&M	SDG&E Capital	SDG&E O&M	Total
Sempra	120,768	1,931	25,949	640	149,288
DRA	48,087	1,564	11,547	279	61,477

III. DISCUSSION / ANALYSIS OF VALVE ENHANCEMENT PLAN

The SoCalGas/SDG&E proposed Valve Enhancement Plan includes two main elements: Valve Enhancements (also refer to as Control Valve Work in the testimony and workpapers) and System Enhancements.[7] Sempra's proposed Valve Enhancements are: upgrading existing manual control valves to ASV/RCV, upgrading existing ASV with RCV functionality, upgrading existing ASV with communications only, and adding new ASVs/RCVs to pipeline system. Sempra's proposed System Enhancement are: adding volume measurement stations on larger pipelines, adding new pilot controls, check valves, RCVs for backflow prevention controls, adding volume measurement stations on tapped/interconnected

[5] *See* Public Utilities Code Section 957.
[6] Sempra dollar amounts calculated from Amended Testimony, p. 113, Table IX-12.
[7] Amended Testimony, p. 114, Table IX-13.

pipelines, expanding central Supervisory Control and Data Acquisition (SCADA) system, and enhancing communication system with private radio networks.[8]

SoCalGas/SDG&E's Phase 1 of the Valve Enhancement Plan covers Years 2012 to 2021 for a total of 10 years. SoCalGas/SDG&E break Phase 1 down to two sub-phases, with Phase 1A covering 2012 to 2015, and Phase 1B covering 2016 to 2021. DRA addresses the Phase 1A proposals in this report.

DRA does not address some of the proposed project elements in this report because it does not object to the SoCalGas/SDG&E's proposals in these areas. These elements include upgrading existing ASV with communications under Valve Enhancements, adding volume measurement stations on larger pipelines, adding volume measurement stations on tapped/interconnected pipelines, and expanding central SCADA system under System Enhancements. The total proposed capital and O&M expenditures in Phase 1A for these elements are $9.5 million. SoCalGas/SDG&E indicate in the testimony that most of the ASVs currently in their system are not equipped with telemetry and/or SCADA remote data monitoring capabilities.[9] Funding for these elements will serve to improve and modernize the monitoring capability of the transmission system, with or without the upgrading of most manual valves to ASV/RCV. If operational anomalies occur in the transmission system, the relevant information will flow to the appropriate control center in a timely manner with these enhancements. The safety of the pipeline system should improve with these additions.

DRA discusses Valve Enhancement work in Section A, and System Enhancement work in Section B.

A. Valve Enhancements

In Phase 1A, SoCalGas and SDG&E propose upgrading existing manual control valves to ASV/RCV and upgrading existing ASVs with RCV functionality.[10]

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[8] Amended Testimony, p. 114, Table IX-13.

[9] Amended Testimony, p. 71, Lines 7 to 9.

[10] Amended Testimony, p. 114, Table IX-13.

The evaluation process SoCalGas/SDG&E used to choose which valves to upgrade to ASV/RCV and where to add new ASVs/RCVs is shown on a decision tree in its testimony.[11] The process involved evaluating all transmission pipeline segments twenty inches in diameter or larger, lines between twelve and twenty inches in diameter that operate at 30% or more of Specified Minimum Yield Strength (SMYS), and transmission pipelines that cross a known geological threat. As a result of the evaluation, the Sempra utilities propose to upgrade 347 existing manual control valves to ASV/RCV, 94 existing ASV with RCV functionality, and add 20 new ASVs/RCVs to the pipeline system over the 10-year Phase 1 period.[12] In Phase 1A, the utilities propose to upgrade 131 of the existing manual control valves to ASV/RCV (105 for SoCalGas and 26 for SDG&E), and upgrade 30 of the existing ASVs with RCV functionality (all SoCalGas).[13]

The primary benefit of the ASV/RCV is to stop the release of natural gas in a short time after a pipe break incident. Studies have shown that the ASV/RCV will not react quickly enough to prevent serious consequence after pipeline failure.[14] SoCalGas/SDG&E point out in their testimony that errant closures remain an operational risk even with the improvement in control technology and equipment reliability. These closures can occur due to equipment failure, spurious pressure waves, or other operational issues that can shutdown a critical pipeline serving a large number of customers.[15] These points were highlighted again in a recent Congressional Research report.[16] The American Gas Association announced that

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[11] Amended Testimony, p. 80, Figure V-4.

[12] Amended Testimony, p. 81, Table V-1.

[13] Amended Workpapers, Chapter IX, pp. WP-IX-2-62 of 116, WP-IX-69 of 116, WP-IX-75 of 116.

[14] AGA White Paper: Automatic Shut-off Valves (ASV) and Remote Control Valves (RCV) on Natural Gas Transmission Pipelines, AGA Distribution & Transmission Engineering Committee, March 25, 2011.

[15] Amended Testimony, pp. 73 to 74.

[16] Paul W. Parformak, Keeping America's Pipelines Safe and Secure: Key Issues for Congress, Congressional Research Service Report for Congress, March 13, 2012, pp. 19 to 24.

they are developing a more comprehensive technical paper that presents benefits and disadvantages of the installation of ASV/RCV block valves on new, fully replaced and existing transmission pipelines. This paper is scheduled to be released in September 2012.[17]

In a data response to DRA, SoCalGas/SDG&E indicate that with its approximately 200 ASVs/RCVs currently in operation, there were five false activations in 2011,[18] and about one event per year over the past 14 years involving the closure of an ASV due to either legitimate operational pressure drops or other pipeline problems warranting closure.[19] Sempra does not have documented reliability data on the performance of ASVs/RCVs from other pipeline operators in the US and the world.[20]

More operating experience is highly desirable in order to better and more thoroughly assess the merit of ASV/RCV's safety benefit, especially in highly populated urban areas. Currently, most of the ASVs/RCVs operated by the Sempra utilities are installed in rural areas far from Class 3 and Class 4 areas or Class 1 and Class 2 HCA.

The validity of the cost estimates for the Valve Enhancement Plan is difficult to assess. SoCalGas/SDG&E acknowledge in their testimony that "Cost estimates are preliminary and were developed based on minimal engineering, operational planning, and project execution planning."[21] SoCalGas/SDG&E have not provided relevant automatic valve replacement cost history. As a result, there is a great degree of uncertainty embedded in the utilities' cost projections. Before the Commission can determine whether the forecasts of the Sempra utilities' Valve Enhancement Plan are reasonable, the utilities should be required to provide more

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17 AGA's Commitment to Enhancing Safety_May 2012, American Gas Association.

18 Responses to Data Request DRA-KCL-3, Questions 3 and 4.

19 Response to Data Request DRA-KCL-3, Question 2,.

20 Response to Data Request DRA-KCL-3, Question 7,.

21 Amended Testimony, p. 103, Lines 23 to 24.

detailed and reliable projections based on actual cost data from a sufficient number of completed and comparable automatic valve upgrade projects that can be obtained over the next few years.

As described above, Legislature has directed the Commission to ”... require the installation of automatic shutoff or remote controlled sectionalized block valves on both of the following facilities, if it determines those valves are necessary for the protection of the public.”[22] When it initiated the Rulemaking to adopt new safety and reliability regulations for natural gas pipeline operators, the Commission stated:

> Given the economic challenges confronting California’s families and businesses, we must be certain that each investment in safety that we order provides value to customers....[23]

SoCalGas/SDG&E have not provided any verifiable data to demonstrate that their proposed Valve Enhancement Plan is “necessary for the protection of the public,” or that it provides “value to its customers.”

Given the lack of information about ASV/RCV installation and operating experience in urban and highly populated areas, the uncertainty in Sempra’s cost estimates, the absence of any detailed cost/benefit studies, and the upcoming release the AGA comprehensive technical paper on ASV/RCV benefits and disadvanges, DRA recommends that SoCalGas/SDG&E launch the Valve Enhancement Plan Phase 1A at a more measured pace than the utilities proposed. DRA recommends reducing the valve upgrades by 50 percent with the upgrade of 65 existing manual control valves to ASV/RCV (52 for SoCalGas and 13 for SDG&E) instead of 131, and the upgrade of 15 existing ASVs with RCV functionality instead of 30. Rather than proceeding rapidly with the full proposed program given its many uncertainties, SoCalGas/SDG&E should proceed with its Valve Enhancement Plan gradually to move from what is essentially its current “conceptual design” stage into the engineering and production stage. The utilities will gain valuable experience in cost forecasting, engineering, installation, operation, benefits, and value of the

[22] Public Utilities Code Section 957.

[23] Rulemaking 11-02-019, p. 11.

ASV/RCV program. With this additional experience in cost, engineering, installation, and operation, and after performing the necessary detailed cost/benefit analyses, the utilities can then propose a more informed implementation plan in subsequent GRCs .

The reduction of valve upgrade work by 50 percent is consistent with the comments of the Consumer Protection and Safety Division (CPSD) of the CPUC that:

> ... the [Sempra utilities'] proposed number of automated valve installations could potentially be decreased if they were to install ASVs at less frequent spacing than that at which they now propose to install RCVs.[24]

The utilities can space the automatic valves at 16 miles apart in contrast to the approximately 8 miles proposed, and be able to stop the flow of gas within 30 minutes. CPSD states , "If the CPUC is willing to accept some risk of false closure, the number of automated valves proposed in the PSEP could be reduced with the installation of ASVs, at intervals longer than those being proposed by the Companies for RCV installations, and still ensure that gas flow is stopped within 30 minutes of a full breach of the pipeline."[25] DRA recommends that the utilities perform the valve retrofits at 16 mile spacings and monitor the operation of these installed valves in ASV mode during the next four years (2012-2015).

SoCalGas/ SDG&E will be spending less than the proposed amount in 2012 ($2.78 million instead of $23.54 million for SoCalGas on upgrading manual valves to ASV/RCV)[26] because they have not done any replacement in the first 5 months of 2012. This results in a reduction of $20.76 million for 2012. When the reduction in 2012 spending is combined with DRA's recommended 50% reductions in the valve upgrade proposals for 2012 through 2015, the total expenditures in Phase 1A for

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[24] Technical Report of CPSD Regarding the SoCalGas/SDG&E PSEP, R.11-02-019, January 17, 2012, p. 15.

[25] Technical Report of CPSD Regarding the SoCalGas/SDG&E PSEP, R.11-02-019, January 17, 2012, p. 16.

[26] Response to Data Request DRA-KCL-TCAP-PSEP-05, Question 1.

Valve Enhancements will be $52 million, which is $70 million lower than the utility forecast of $122 million (see Tables 4 and 5). The utilities' proposed expenditures are shown in Table 4, and the DRA recommended expenditures are shown in Table 5.

Table 4. Proposed Phase 1A VEP Cost Summary by Element[27]
(in thousands of dollars)

	SDG&E Capital	SoCalGas Capital	SDG&E O&M	SoCalGas O&M
Manual to ASV/RCV	20,792	93,895	93	335
ASV to RCV	0	6,662	0	59
Communication to 100 ASVs	0	55	0	8
Large Meter Stations	365	2,126	3	17
Backflow Controls	933	5,436	4	24
Small Meter Stations	237	1,384	2	13
SCADA Expansion	549	3,201	228	1,329
Communication Enhancements	3,074	8,010	309	145
Total	25,949	120,768	640	1,931

[27] Amended Testimony, p. 114, Table IX-13

Table 5. DRA Recommended Phase 1A Cost Summary by Element (in thousands of dollars)

	SDG&E Capital	SoCalGas Capital	SDG&E O&M	SoCalGas O&M
Manual to ASV/RCV	10,396	37,990	46	167
ASV to RCV	0	3,331	0	30
Communication to 100 ASVs	0	55	0	8
Large Meter Stations	365	2,126	3	17
Backflow Controls	0	0	0	0
Small Meter Stations	237	1,384	2	13
SCADA Expansion	549	3,201	228	1,329
Communication Enhancements	0	0	0	0
Total	11,547	48,087	279	1,564

B. System Enhancements to Support Valve Enhancement

The Sempra utilities propose five project elements in "System Enhancements to Support Valve Enhancements."[28] For Phase 1A, DRA recommends no ratepayer

[28] Amended Testimony, p. 81.

funding of two of the proposed System Enhancements: 1) the adding of new pilot controls, check valves, RCVs for backflow prevention controls, and 2) the enhancing of communication system with private radio networks. These two tasks are beyond the scope of the Decision ordering the filing of the Implementation Plan. The Decision states that the priority should be transmission pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 HCAs. Section 957 of the Public Utilities Code also clearly states that the automatic valve upgrade work pertains to intrastate transmission lines.

The proposed tasks of (1) adding new pilot controls, check valves, RCVs for backflow prevention controls, and (2) enhancing communication system with private radio networks appear to be related to the gas distribution system as all the costs are allocated to the distribution system.[29] If SoCalGas/SDG&E can justify these tasks with a cost/benefit analysis relative to the transmission system, they may be more appropriately considered as integrity management projects in the subsequent GRCs.

The adjustment to the Valve Enhancement Plan cost forecasts for the new pilot controls, check valves, RCVs for backflow prevention controls task reduces the proposed expenditures by $6.397 million in Phase 1A. The adjustment for the communication system enhancements task reduces proposed expenditures by $11.538 million in Phase 1A.

IV. CONCLUSION

DRA's recommended adjustments to Valve Enhancement (Valve Control Work) and System Enhancement, reduce Phase 1A VEP cost from the SoCalGas/SDG&E proposed $149.3 million to $61.5 million. The yearly expenditures with the DRA recommended adjustments are shown in Table 6.

[29] Amended Workpapers, Chapter IX, pp. WP-IX-91 of 116, WP-IX-95 of 116, WP-IX-98 of 116, WP-IX-110 of 116, WP-IX-113 of 116.

Table 6. DRA Recommended VEP Cost Summary for Phase 1A

(in thousands of dollars)

SoCalGas	2012	2013	2014	2015	Total
Capital	$ 3,312	$13,378	$15,699	$15,698	$ 48,087
O&M	$ 33	$ 148	$ 654	$ 732	$ 1,567
Total	$ 3,345	$13,526	$16,353	$16,430	$ 49,654
SDG&E					
Capital	$ 3,090	$ 2,690	$ 3,083	$ 3,083	$ 11,946
O&M	$ 8	$ 29	$ 114	$ 127	$ 278
Total	$ 3,098	$ 2,719	$ 3,197	$ 3,210	$ 12,224

ATTACHMENT 1

Data Responses

<u>QUESTION KCL3-1:</u>

Lines 19 to 20 on Page 67 indicate that Sempra currently has over 200 ASVs and RCVs in operation. How many of these are ASVs and how many are RCVs? Are any of them located in HCA and/or class 3/class 4 locations?

<u>RESPONSE KCL3-1:</u>

Table DRA-KCL-3-1.1 provides the requested information. Note that valves protecting pipeline segments located in high consequence areas themselves may be located <u>outside</u> of high consequence areas. Therefore, in the table below we include more comprehensive information to indicate the number of ASV and RCV valves that currently protect high consequence areas in Class 3 and 4 locations.

Table DRA-KCL-3-1.1

Description	Total Valve Count	Associated subset of valves protecting Class 3/4 and/or HCA pipeline segments at 5-20 miles.
RCVs*residing in Class 3/4/HCA locations.	39	39
RCVs * residing outside Class 3/4/HCA locations	34	17
ASVs residing in Class 3/4/HCA Locations.	79	79
ASVs residing outside Class 3/4/HCA locations.	115	62
Under review.	5	4
Total	***272***	***201***

*Does not include smaller RCVs associated with compressor station mode and internal operational controls. Limited to valves directly associated with main pipeline operations.

QUESTION KCL3-2:

How many times have the ASVs and RCVs described above been activated because of a real pressure drop incident? Please describe each incident in detail, including the pressures levels and final valve position (fully or partially closed).

RESPONSE KCL3-2 **(Table DRA KCL-3-2 Amended 3/8/12 to include pressure files associated with incidents dated 7/11/2011 and 8/7/2010. No other Pressure data available – beyond data retention period. Note each file shows the distance from the incident associated with each pressure measurement location. Pressures (max, min and average) in all files shown as psig.)**

Based on a fourteen-year period review, collectively, SoCalGas and SDG&E average roughly one event per year involving the closure of an ASV due to either legitimate operational pressure drops or other pipeline problems warranting closure. The most recent activation of a linebreak control associated with a SoCalGas pipeline (Line 404) rupture is described on page 72 of our Testimony.

Table DRA-KCL-3-2 below chronicles the companies' thirteen most recent major pipeline ruptures/gouge events which involved credible pressure excursions constituting ASV closure-for-cause. In ten out of eleven instances where ASVs were installed within five miles of the rupture, and where the pressure drop parameters exceeded allowable limits, the valves fully closed, as-engineered. In one instance, a valve experienced partial closure.

Table DRA-KCL-3-2:

Added 3/8/12 – Files of closest available pipeline pressure recordings during the incident day, where available, are attached. Data includes max, min and average values for each hour. Red line entries in data files show incident hour.

Date	Pipeline/Event	ASV#/state	ASV#/state
7/10/2011	L404 mp 28.48 rupture-farm equipment. Pressure data file attached	MLV 404-20.81 /ASV fully-closed (1/1).	MLV 404-30.48/ASV fully-closed (2/2).

	3/8/12-incident date revised. 07102011incident.1.xls		
8/7/2010	L85/gouge-farm equipment. Pressure data file attached 3/18/12. 08072010incident.2.xls	Manual valves closed	Manual valves closed
2007	L6001-2/ rupture.-bombed by military. Pressure Data Not Available (3/8/12).	Manual valves closed.	Manual valves closed
2005	L85/rupture-landslide Pressure Data Not Available (3/8/12).	Under review at document release.	Under review at document release.
2/28/2005	L324/rupture – landslide Pressure Data Not Available (3/8/12).	MLV 324-6/ASV fully-closed (3/3).	MLV 324-7/ASV fully-closed (4/4).
12/11/2003	L800 mp 5.14/gouge-farm equipment. Pressure Data Not Available (3/8/12).	Manual valves closed.	Manual valves closed
2002	L8109/ rupture-landslide. Pressure Data Not Available (3/8/12).	MLV 8109-18.08 ASV fully closed. (5/5)	MLV/Manually closed.
1/16/2002	L85/gouged-farm equipment. Pressure Data Not Available (3/8/12).	Manual valves closed.	Manual valves closed.
2/2/2001*	L85/gouged-farm equipment. Pressure Data Not Available (3/8/12 – incident date refined).	Manual valves closed.	Manual valves closed
3/2/98*	L406-mp 12.66/ rupture landslide. Pressure Data Not	MLV 404-12.48/ASV fully- closed (6/6).	MLV 404-19.39/valve manually closed.

	Available (3/8/12 – incident date revised).		
3/1/98	L404-mp 13.63 /rupture/landslide. Pressure Data Not Available (3/8/12).	MLV 404-13.48/ASV fully-closed (7/7).	MLV 404-16.99/ASV fully- closed (8/8).
2/17/98	L1004-mp 31.58 /rupture-landslide. Pressure Data Not Available (3/8/12).	1004-29.38/ASV fully-closed (9/9).	34.18/ Manual valve closed at manned. station.
2/14/98	L404-mp 2.28/rupture-landslide/mp. Pressure Data Not Available (3/8/12).	404-0.00/ASV ***partial-closure (9/10)***	404-3.71/ASV fully-closed (10/11).

Table Note “mp”=pipeline milepost.

<u>QUESTION KCL3-3:</u>

How many times have the ASVs and RCVs described in KCL3-1 been activated because of a false alarm? Please describe each incident in detail, including the pressures levels and final valve position (fully or partially closed).

<u>RESPONSE KCL3-3 (Amended 3/8/12 to include pressure data files, where available, associated with each ASV incident. Note each file shows the distance from the incident associated with each pressure measurement location. Pressures (max, min and average) in all files shown as psig) See Amended Response KCL 3-4 for RCV information:</u>

Attached is a listing of 2011 spurious ASV closures and/or, where known, causes. This information was extracted from operational logs. Year 2011 was a typical year with five events registered.

Date: 12/26/11
*Incident: V4 (**225-29.68 -0)** Levelle Rd. Linebreak valve at Wheeler Ridge Compressor Station closed. Controller experienced abnormal pressure readings. Technician discovered valve closed and reopened it. No indication as to why it closed.*

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

fa1_Dec2011whlg
or.xls

Date: 9/18/11
*Incident: V18 (**235-181.57-0)** L-235 Linebreak valve near Adelanto compressor Station closed. Controller experienced abnormal pressure readings. Technician discovered valve closed and reopened it. No indication as to why it closed.*

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

fa2_Sep2011AdlPl
m.xls

Date: 9/16/11
*Incident: V12 (**2000-125.13-0)** L-2000 Linebreak valve at Whitewater Reg. Station closed. Controller experienced abnormal pressure readings. Valve tripped due to line pressure swings caused by station regulation setup at Whitewater. Valve reopened.*

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

fa3_Sep2011wwt
wwt.xls

Date: 5/18/11
*Incident: V4 (**225-29.68-0)** Levelle Rd. Linebreak valve at Wheeler Ridge Compressor Station closed. Controller experienced pressure changes due to Wheeler Ridge compressor shutdown. Valve reopened.*

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

fa4_May2011GorN
WhlS.xls

Date: 3/26/11
*Incident: V20 (**2000-181.34-0)** L-2000 Linebreak valve near Corona closed. Controller experienced abnormal pressure readings. Technician discovered valve closed and reopened it. No indication as to why it closed.*

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

fa5_Mar2011MorPra.xls

See edits to KCL-3-4 for pressures associated with RCV problems, where available.

QUESTION KCL3-4:

What is Sempra's assessment on the reliability of its ASV systems and its RCV systems? What is the probability (in percentage of being successful?) that either system will perform as anticipated when real emergency situations occur? Please respond and provide documentations.

RESPONSE KCL3-4 **(Amended 3/8/12 to include pressure data files, where available, associated with each RCV incident presented in this Response. Note each file shows the distance from the incident associated with each pressure measurement location. Pressures (max, min and average) in all files shown as psig):**

ASVs:

The requested analytics are not compiled by SoCalGas or SDG&E as a normal course of operations. We have only identified one instance in the last fourteen years where an ASV that was supposed to fully close based on pressure drop parameters failed to do so (a partial closure was experienced). On that basis, the empirical system Mean-Time-Between-Failure for closure-when-required could be calculated at 1/(365/24/194/14) or 25 Million hours.

However, a simple analysis of Table DRA-KCL-3-2 shows that of the eleven valves that should have fully closed due to ruptures over the fourteen-year period, one valve experience a partial closure. Categorizing this partial closure as a failure would place the experienced reliability of closure when called upon to isolate a rupture at 91% over the fourteen-year period.

The larger issue for SoCalGas and SDG&E in terms of system reliability is the closure of a valve for reasons other than a pipeline rupture. Such closures can potentially result in wide-scale customer outages if not properly planned for in base ASV system design. With five such instances chronicled in 2011, the mean-time-between failure for ASVs can logically and nominally be computed as 1/(5/365/24/194) or 339,888 hours. This translates into a calculated reliability (CR) as follows:

CR=(1-(1/339,888)*100=99.9%

RCVS:

The information below on RCV problems encountered in 2011 was extracted from operational logs.

Date: 12/11/11
*Incident: V8 (**2000-155.06-8)** at Moreno Reg. Station would not close. Controller unable to operate valve remotely. Technician lubed valve to close and returned to service.*

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

mf1_Dec2011L2kPraMor.xls

Date: 11/3/11
*Incident: V3 (**3000-248.48-0)** at Balboa Reg. Station not responding to set point control. Controller unable to operate valve remotely. Technician found valve stuck in closed position. Valve cycled and returned to service.*

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

mf2_Nov2011BalBal.xls

Date: 11/1/11
Incident: V519-2 at Newberry Compressor Station not responding to commands. Controller unable to operate valve remotely. Technician found hydraulic leak. Repairs made, valve returned to service.

Added 3/8/12 – File of closest available pipeline pressure recordings during the incident day is attached. Data includes max, min and average values for each hour.

mf3_Nov2011Nbr4kNbr3k.xls

In addition there were two valve station failures associated with electrical power surges and/or lightning strikes that compromised electronic controllers used to remotely control valves in 2011. At two valves per station rendered inoperable for each incident, this brings the total count of RCVs that experienced some operational problem, when called upon for service, in 2011 to seven (7). Assuming operations personnel averaged one control valve command function initiation per hour for the year, these seven failures translate into a composite reliability calculated as (1-7/365/24) or 99.94%.

QUESTION KCL3-5:

How did Sempra check the performances of the ASV/RCV systems when they were first installed? Explain how and how frequently does Sempra check/activate the ASV/RCV systems to make sure they still work in the field over time? Please respond and provide documentations.

RESPONSE KCL3-5:

SoCalGas and SDG&E test each base valve for operational integrity annually.

Beyond basic valve compliance-related testing, where electronic linebreak controls and PLCs are employed, these devices are also tested and inspected following installation and on an annual schedule thereafter to ensure power systems, pressure sensors, control systems, control gas regulators and logic programs are calibrated and/or functional. To test base functionality, a known pressure drop (based on engineering calculations provided for a specific section of pipeline) is introduced to the sensor that monitors for a pre-set pressure drop threshold to activate a switch to drive the valve to close. Operation is confirmed when that pressure drop results in positive control system closure activation. These tests are conducted outside of (in addition to) the basic overpressure protection system inspection protocols required by the CPUC.

A field instructional guideline on ASV inspection ("Line Guard Inspection instruction.doc") is attached electronically.

Line Guard
Inspection instruction

QUESTION KCL3-6:

Does Sempra have any documented action plans in the event the ASVs/RCVs fail to perform during real emergencies? Please provide such plans if they are available or explain if they are not available.

RESPONSE KCL3-6:

Closure (or non-closure) of an ASV or RCV are treated as any other high-priority operational call-outs that may have acute impacts on our ability to serve customers. Gas Transmission field personnel are called directly and immediately after control room assessment that conditions warrant further action. Field personnel who monitor SCADA operations directly can also self-initiate an investigative dispatch.

SoCalGas Standard 223.0031 covers general transmission system Emergency and Abnormal Operating Condition protocols where the dispatch of field personnel is required. This document is available for review/inspection at our Gas Control Center or other SoCalGas facility.

QUESTION KCL3-7:

Does Sempra have any documented reliability data on the performance of ASV/RCV from other pipeline operators in the US and around the world? Please provide these data if they are available.

RESPONSE KCL3-7:

No.

QUESTION KCL3-8:

In the testimony, Sempra indicates that all the automatic valves will have both ASV and RCV capability. Please explain what that statement means. Will the valves be set to either ASV or RCV mode, or both modes simultaneously? If both modes simultaneously, then please explain the operational sequence.

RESPONSE KCL3-8:

The planned valve controls can be set to provide for either mode of operation or both modes simultaneously. Detailed analyses and operational histories for specific pipelines will ultimately determine which mode(s) will be activated at a given location. And these designations may change over time, depending on lessons learned, changes in operational flow patterns and introduction of new customers and pipeline assets into the operational plan. The expected configuration at most locations will be to provide the ASV functionality first, but also to enable operators to remotely control the same valves as conditions verified by enhanced control room diagnostics and/or field observations warrant.

QUESTION DRA-KCL-TCAP-PSEP 05-01:

In SoCalGas/SDG&E's valve enhancement plan, SoCalGas allocated $26.328 million for valve upgrade and other associated work in 2012, and SDG&E allocated $5.36 million in 2012. Please provide details on what tasks were completed or are still in progress so far this year and how much of the allocated expenditures were expensed. Please also provide details on the work planned and the estimated expenditures for the rest of 2012.

RESPONSE DRA-KCL-TCAP-PSEP 05-01:

The SoCalGas/SDG&E PSEP has not yet been approved by the CPUC. However, some of the work locations identified in the PSEP are at valve sites where work associated with Pipeline Integrity Plan (PIP) operations is scheduled to be performed in 2012. Where this has occurred, or will occur in 2012, and where work identified in the PSEP can be logistically and cost-effectively co-performed in 2012, rather than requiring return at a later date, such work has been planned and, in some instances, completed in conjunction with PIP work. The scope of work completed at each site, and/or to be completed by the end of 2012 ranges from base installation of a valve, with no actuator, to complete ASV and RCV capability at the indicated location.

The attached electronic table is a modified excerpt of the detailed PSEP transmission valve location matrix, which starts on Plan Workpaper page WP-IX-2-14 (also known as Attachment Valves_Cap-2).

Data_Request_DRA-KCL-05_valve_work i

This modified table contains four added columns for this data request as follows:

- Column A - Projected costs for all PSEP-identified work to be completed by the end of the year 2012 at specific valve locations;

- Column B - Projected cost for all combined PSEP and PIP work at the indicated valve locations to be completed by the end of year 2012;

- Column C – Estimated, and in some instances actual cost incurred as of 5-22-12 at the indicated valve work location via both PIP and PSEP activities;

- Column D – brief description of work to be completed by the end of 2012 at the referenced valve site.

Year 2012 work sites are referenced in yellow and red row colors. Yellow indicates installation work underway or complete; red indicates valves removed from service and which may be removed from the PSEP, or which will be replaced in the PSEP isolation plan by an alternate valve site(s).

Data in the supplemental columns provide the information requested. A summary of 2012 costs are tabulated at the bottom of the columns. An excerpt is provided in the following table.

2012 Totals

		$ 9,087,000	**$ 18,509,000**	**$ 10,092,930**
		$ 6,307,000	$ 14,769,000	$ 8,408,430
		$ 2,780,000	$ 3,740,000	$ 1,684,500

The table shows a total of $9,087,000 in PSEP-delineated work will be completed in 2012. Of this total, $6,037,000 is SDG&E system work (mainly Lines 3010 and 1601) while the remaining $2,780,000 is work to be completed on the SoCalGas transmission system.

The middle column represents the cost of all planned 2012 work at valve sites referenced in the PSEP, including those cost planned and funded by Pipeline

Integrity programs. The far right column is total expenses incurred to-date at PSEP valve locations in 2012.

There are no other categories of accelerated PSEP Valve work planned in 2012 other than that shown for the major valve locations indicated in the attachment.

QUESTION DRA-KCL-TCAP-PSEP-05-02:

Please provide a detailed updated work plan and yearly expenditure profile of SoCalGas/SDG&E's valve enhancement plan with the PSEP finally incorporated into the TCAP and the approval of the memorandum account.

RESPONSE DRA-KCL-TCAP-PSEP-05-02:

The SoCalGas/SDG&E valve work plan scope and yearly expenditures remain as forecasted in the PSEP work papers with the exception that all costs and related activities have been pushed back due to delay in Plan approval.

QUESTION DRA-KCL-TCAP-PSEP-05-03:

Please provide in detail any actual labor and material cost information on valve upgrade work and new valve installation work that Sempra completed recently that is similar to the types of work SoCalGas and SDG&E proposed in the PSEP valve enhancement plan. Please provide in detail Sempra's historical cost information on such tasks also.

RESPONSE DRA-KCL-TCAP-PSEP-05-03:

SoCalGas/SDG&E object to this request as vague with respect to the phrase "similar types of work. . . " Subject to and without waiving the foregoing objection, SoCalGas and SDG&E respond as follows:

See the table below for information that SoCalGas and SDG&E interpret to be responsive to this request. The most relevant costs are those for five valves that were replaced in San Diego along Pipeline number 3010 in year 2012. These valves reflect the installation complexity, control apparatus required, and site conditions anticipated throughout the utilities' Plan implementation. Five additional SoCalGas historical installations of lesser complexity and scope are also included to provide a perspective on cost ranges.

Table DRA-KCL-05-03:

Recorded SDG&E and SoCalGas Valve Installation Costs – Recent Construction.

					Cost: Direct $ in 2011 and 2012					
Company	**pipeline#**	**Valve#**	**milepost or other ref.**	**Work Scope**	**Total Job cost Direct $**	**Labor**	**non-labor**	**contract**	**materials**	**Actual Spend as of 5-21-12**
SDG&E	3010	3010-3010-0	3010-7.79-0	Install new valve, actuator and ASV/RCV controls. Direct bury. Year 2012	$ 1,853,979	$ 110,715	$ 220,890	$ 906,772	$ 615,602	$ 1,677,430
SDG&E	3010	3010-3009-0	3010-14.18-0	Install new valve, actuator and ASV/RCV controls. Direct bury. Year 2012	$ 1,282,201	$ 100,715	$ 171,517	$ 634,632	$ 375,337	$ 1,242,201
SDG&E	3010	3010-3006-0	3010-30.21-0	Install new valve, actuator and ASV/RCV controls. Direct bury. Year 2012	$ 1,702,430	$ 130,715	$ 200,890	$ 906,772	$ 464,053	$ 1,702,430
SDG&E	3010	3010-3005-0	3010-34.99-0	Install new valve, actuator and ASV/RCV controls. Direct bury. Year 2012	$ 1,016,616	$ 80,715	$ 134,374	$ 563,291	$ 238,236	$ 970,316
SDG&E	3010	3010-3004-0	3010-38.57-0	Install new 30" valve, actuator and ASV/RCV controls. Direct bury. Year 2011/12	$ 1,204,919	$ 120,715	$ 175,880	$ 486,538	$ 421,786	$ 1,108,695
SDG&E	3010	3010-3003-0	3010-43.59-0	Install new 30" valve, actuator and ASV/RCV controls. Direct bury. Year 2011/12	$ 1,148,695	$ 110,715	$ 148,000	$ 542,760	$ 347,220	$ 1,108,695
SoCalGas	335		Aqua Dulce	Install a new 30" valve, actuator and simple ASV control in open range area with limited installlation complexity. Year 2011.	$ 599,087	$ 73,568	$ 48,888	$ 264,827	$ 211,804	$ 599,087
SoCalGas	235	17A	Victorville	Install service and monitor valves at same location to control pressure	664,070	68,824	37,375	274,312	283,559	664,070
SoCalGas	2000	20	Chino Station	Replace actuator on 36" pipeline at compressor station stem exposed, valve already tie into SCADA, Simple upfit	77,766	18,934	2,323	3,180	53,329	77,766
SoCalGas	1185	1A	Adelanto Station	Replace actuator on 36" pipeline at compressor station stem exposed, valve already tie into SCADA, Simple upfit	51,900	4,000	1,700	4,700	41,500	51,900
SoCalGas	324		Vent-Suag	34" Valve/actuator Installation with linebreak control no SCADA no vault.	258,476	20,789	28,063	98,558	111,066	258,476

ATTACHMENT 2

Qualification Statement

QUALIFICATIONS AND PREPARED TESTIMONY

OF

KELLY C. LEE, P.E.

Q.1 Please state your name and address.

A.1 My name is Kelly C. Lee. My business address is 505 Van Ness Avenue,

San Francisco, California, 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Senior Utilities Engineer in the Division of Ratepayer Advocates Energy Cost of Service and Natural Gas Branch.

Q.3 Please describe your educational background and work experience.

A.3 I have a Bachelor of Science Degree in Mechanical Engineering from San Jose State University, a Master of Science Degree and a Master of Engineering Degree from the University of California in Berkeley, and a Master of Business Administration (MBA) from the University of San Francisco.

I joined the Commission in 1999, where I have worked as an analyst and project coordinator on various gas, electric, and telecommunication cases. Before joining the CPUC, I worked in the private industry performing engineering research and analysis, managing programs, and supervising engineers in the aerospace and alternate energy fields.

Q.4 Are you a registered professional engineer?

A.4 Yes, I am a registered Professional Engineer in Mechanical Engineering in the State of California.

Q.5 What is your area of responsibility in this proceeding?

A.5 I am responsible for Exhibit DRA-3 which addresses the SoCalGas/SDG&E Valve Enhancement Plan.

Q.6 Does that complete your prepared testimony?

A.6 Yes, it does.